Bonterra Energy Corp.

2000 ANNUAL REPORT

Bonterra
Energy Corp.

Table of Contents

Notice of Annual Meeting

The Annual Meeting of Shareholders will be held on Monday, June 25, 2001, in the Bonavista Room at the Westin Hotel, 320 Fourth Avenue S.W., Calgary, Alberta, at 11:00 a.m. (Calgary time).

Corporate Profile

Bonterra Energy Corp. (Canadian Venture Exchange - BON) is a junior resource company that explores for, develops and produces oil and natural gas in the Provinces of Alberta and Saskatchewan.

The Company's business strategy is to strive to maximize shareholder value by applying long-term growth objectives. The Company's primary objective is to combine its oil and gas production technical strengths with planned business strategies to generate above average results and returns for our shareholders.

Highlights	2000	1999
FINANCIAL ($000, except $ per share)		
Revenue – oil and gas (net of royalties)	$21,682	$ 13,214
Cash Flow from Operations	9,386	3,829
Per Share Basic	0.30	0.12
Per Share Fully Diluted	0.27	0.11
Net Earnings	5,970	676
Per Share Basic	0.19	0.02
Per Share Fully Diluted	0.17	0.02
Capital Expenditures and Acquisitions	2,439	122
Outstanding Debt	3,928	15,048
Shareholders' Equity	9,270	3,286
Shares Outstanding (weighted average) (000's)	31,678	31,542
OPERATIONS		
Oil and Liquids (barrels per day)	1,510	1,576
Average Price ($ per barrel)	$40.19	$23.46
Natural Gas (MCF per day)	809	821
Average Price ($ per MCF)	$ 5.17	$ 2.80
RESERVES (proven producing)		
Oil and Liquids (barrels in 000's)	7,162	7,674
Natural Gas (MCF in 000's)	3,595	3,149
KEY RATIOS		
Rate of Earnings on Capital Employed	192.6%	21.9%
Rate of Cash Flow on Capital Employed	302.8%	124.1%
Rate of Earnings on Shareholders' Equity	64.4%	20.6%
Rate of Cash Flow on Shareholders' Equity	101.2%	116.5%

Report to Shareholders

The Company is pleased to report its operational and financial results for 2000. Bonterra substantially increased its net earnings and cash flow and substantially reduced its long-term debt. Year 2000 net earnings and cash flow increased by 757 percent and 145 percent, respectively, compared to 1999, and long-term debt reduced to $3,928,000 from $15,048,000 in 1999. This type of success does, however, result in income taxes becoming a significant factor. Bonterra's 2000 cash income taxes increased to $3,254,000 from $213,000 in 1999.

The Board of Directors, after giving consideration to the above results, amongst other things, analyzed various options available to the Company to provide the best rate of return for shareholders. From this analysis the Board unanimously agreed to reorganize the Company into a Royalty Income Trust (Income Trust).

Royalty Income Trust

On March 15, 2001, Bonterra issued a press release disclosing the terms of the reorganization. The transaction will be completed by way of a Plan of Arrangement (the "Arrangement"). It is subject to approval by shareholders at the 2001 Annual and Special Meeting.

The Arrangement will result in the shareholders of Bonterra receiving one trust unit in the Income Trust in exchange for each four common shares of Bonterra resulting in the issuance of approximately 8,692,000 trust units. The Income Trust will be applying for a listing on the Toronto Stock Exchange. Based mainly on independent engineering evaluations and cash flow forecasting and modeling, the Income Trust is forecasting to make monthly distributions to unit holders of approximately $0.15 per unit for the period July 1, 2001, to December 31, 2001, or approximately $1.80 per unit annualized. The first payment will be for the month of July 2001, and will be paid on August 31, 2001.

The forecast prepared used average daily production of 1,950 (91 percent oil and liquids and 9 percent natural gas) barrels of oil equivalent (natural gas converted at 10 to 1). Commodity prices, using Sproule Associates Limited ("Sproule") pricing for 2001, were forecast to be $28.20 U.S. (WTI) per barrel for crude oil and $7.93 Cdn. per MCF for natural gas. The Cdn./U.S. exchange rate used is 0.656. Based on these assumptions the Income Trust is forecasting cash flow from operations of $9,788,000 for the six-month period ending December 31, 2001. The cash flow will be used for: unit distribution of $7,820,000 ($0.15 per month for six months), $750,000 for capital expenditures, and the balance of $1,218,000 to reduce debt or to contribute to unit distribution amounts if commodity prices or production volumes are lower than forecast. Sensitivities of cash flow are 3.4 cents per unit per six-month period for each $1.00 U.S. change in WTI price per barrel and 0.2 of a cent per unit per six-month period for each $0.10 Cdn. change in natural gas prices per MCF.

Bonterra's asset base is comprised of mature oil and gas properties with low risk development potential for its undrilled properties and with very favorable reserve life indexes of 13.2 years for oil and 14.9 years for natural gas and liquids based on proven reserves from a January 1, 2001 independent engineering evaluation by Sproule, and Bonterra's 2000 production volumes.

The Income Trust will grow in size through acquisitions of producing oil and gas properties, acquisitions of companies, mergers with trusts or companies, and by drilling mainly low-risk development prospects. Bonterra believes that there are numerous small companies that are giving consideration to converting their operations into trusts. Bonterra's trust will have lower management and administration costs than most other trusts, which may make it attractive for other companies to become involved in this Income Trust.

The conversion of Bonterra common shares into trust units unfortunately does not qualify for an Income Tax Act Section 85 rollover and therefore is a taxable transaction; most often on a capital gains basis. Your tax advisor should be contacted for further clarification. The Board's view is that the positive aspects of the Income Trust far exceed this negative aspect.

The existing Bonterra Board of Directors have all agreed to continue as directors of the operating company for the Income Trust. The business plan for the Income Trust will undergo few changes from the present company philosophy with the exception that capital investments will be directed towards lower risk properties.

Bonterra Shareholders Opportunity for Additional Investment

The Board of Directors and management believe it is prudent for the existing Bonterra shareholders to have an opportunity to continue investing in higher risk oil and gas projects that may not be appropriate for income trust types of investments.

A new company will be incorporated (Newco) and each Bonterra shareholder of record on June 25, 2001, will be granted warrants to acquire

shares in Newco based on the number of shares held in Bonterra. Exercising of these warrants is not compulsory and will be at the option of each Bonterra shareholder. Newco will make an application to list its shares on the Canadian Venture Stock Exchange.

Operations

The Company continues to operate in two main areas. The Pembina area of Alberta, located near Drayton Valley, accounts for approximately two-thirds of its production, and an additional thirty percent is produced in the Dodsland area of southwest Saskatchewan.

Production volume declined slightly in 2000 to 1,590 BOE/D from 1,658 BOE in 1999 (natural gas converted at 10:1). Production volume is projected to average 1,950 BOE/D for the last half of 2001. Oil production is primarily light sweet gravity crude that, along with natural gas liquids, accounts for approximately 90 percent of the BOE/D. The life index is approximately 13 years which is substantially higher than industry average in the Western Canadian basin.

Financial

Oil and gas revenue (net of royalties) increased by 64 percent to $21,682,000 compared to $13,214,000 in 1999. Cash flow from operations increased by 145 percent to $9,386,000 from $3,829,000 in 1999 despite having to pay cash income taxes of $3,254,000 in 2000 compared to $214,000 in 1999. Net earnings increased to $5,970,000 from $676,000 in 1999. The major portions of the above increases are attributable to higher prices for oil and natural gas and lower interest costs due to reductions in long-term debt, partially offset by an increase in current income taxes and general and administrative expenses.

Cash net backs increased to $15.95 per BOE in 2000 compared to $6.28 per BOE in 1999. Production costs were almost identical between the two years; $7,684,000 in 2000 and $7,705,000 in 1999. The Company's long-term debt of $3,928,000 at December 31, 2000, represents a cash flow to debt ratio of 5 months using year 2000 cash flow. The low level of debt will provide additional opportunities after the reorganization to an Income Trust.

Outlook

The reorganization to an Income Trust will provide an immediate high rate of return or capital gain to shareholders. It should also provide numerous opportunities to grow in the future. One potential opportunity that will be considered during the last half of 2001 will be to merge with a Royalty Income Trust that is presently being planned by Comstate Resources Ltd. ("Comstate"). Comstate, as many of our shareholders know, is a company that has a common Board of Directors and common officers with Bonterra. The two companies also have similar and closely positioned producing properties in the Pembina area of Alberta (both companies' major area of production) and share pipeline and processing facilities. Comstate recently announced that it will be asking shareholders to vote on a reorganization that will result in a separation of oil and gas assets from minerals investments and the establishment of an Income Trust for its oil and gas assets. After the establishment of their respective Income Trusts, both Bonterra and Comstate will be obtaining fairness opinions to determine whether there are sufficient benefits to combine the two Income Trusts.

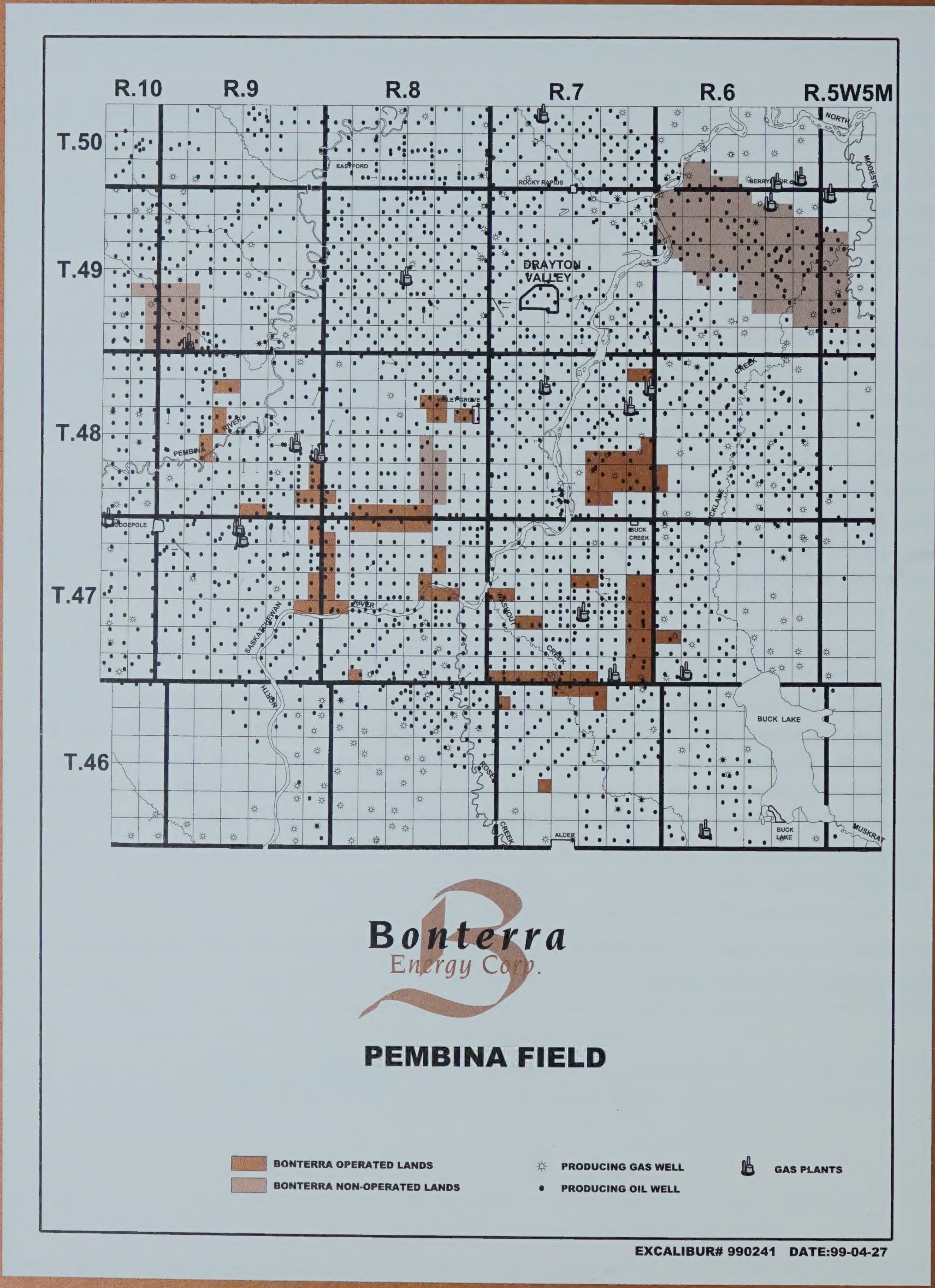
Corporate

The Board of Directors wish to thank its shareholders for their continued support and its staff for its effort and commitment in 2000.

Submitted on behalf of the Board of Directors,

George F. Fink

President and Director



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ROCKY RAPIDS
DRAYTON VALLEY
PEMBINA
RIVER
LODGEPOLE
BUCK CREEK
SASKATCHEWAN
NORTH
CREEK
BUCK LAKE
ALDER
MUSKRAT
NORTH
MODESTE
Bonterra
Energy Corp.
PEMBINA FIELD
BONTERRA OPERATED LANDS
BONTERRA NON-OPERATED LANDS
PRODUCING GAS WELL
PRODUCING OIL WELL
GAS PLANTS
EXCALIBUR# 990241 DATE:99-04-27

Review of Operations

Reserves

The Company engaged an independent engineering firm to prepare the following reserve evaluation. The effective date for this evaluation is January 1, 2001.

The reserves are located in the Provinces of Alberta and Saskatchewan. The majority of the Company's production is comprised of light sweet crude, which results in higher oil prices, and better marketing opportunities. The Company's main oil producing areas are located in the Pembina area of Alberta and Dodsland area of Saskatchewan. Oil and natural gas proven reserve estimates at December 31, 2000, before royalties, are as follows:

	Crude Oil and Liquids		Natural Gas	
	Proven	Probable	Proven	Probable
January 1, 2000	7,674	–	3,149	–
Production	(551)	–	(295)	–
Drilling additions	91	–	236	–
Evaluation adjustments to reserves	74	69	1,299	62
December 31, 2000	7,288	69	4,389	62
Life index (years) – December 31, 2000	13.2		14.9	
Life index (years) – December 31, 1999	13.3		10.5	

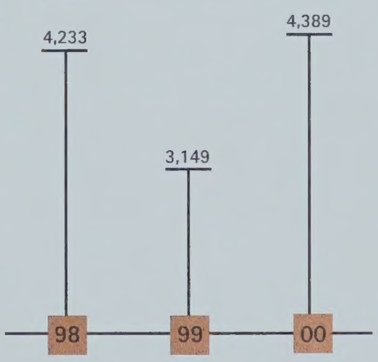
OIL AND NGL RESERVES

Proven (MBbls)

The reserve values in the following table, "Estimated Present Worth of Future Net Production Revenue", are based upon proven producing reserve estimates at December 31, 2000.

NATURAL GAS RESERVES

Proven (MMCF)



ESTIMATED PRESENT WORTH OF FUTURE NET PRODUCTION REVENUE

		Discounted at the rate of		
($ thousands)	Undiscounted	10%	12%	15%
Proven reserves				
Proven producing	107,409	60,204	55,680	50,237
Proven developed non-producing	2,775	2,028	1,934	1,811
Proven undeveloped	1,639	1,189	1,126	1,043
Total proven reserves	111,823	63,421	58,740	53,091
Probable reserves, risked at 50%	1,126	469	406	332
Proven and probable reserves at December 31, 2000	112,949	63,890	59,146	53,423
Proven and probable reserves at December 31, 1999	62,900	32,700	30,100	27,300
Increase	80%	95%	96%	96%

Commodity prices used in the above calculations of reserves are as follows:

Year	Edmonton Par Price (Cdn $ per barrel)	Alberta Index Plantgate (Cdn $ per MCF)	Propane (Cdn $ per barrel)	Butane (Cdn $ per barrel)	Pentane (Cdn $ per barrel)
2001	41.87	7.93	28.97	31.21	46.97
2002	35.85	5.73	23.63	25.39	38.39
2003	30.44	4.30	19.06	20.42	32.03
2004	30.95	3.91	18.35	19.61	31.98
2005	30.96	3.91	17.34	18.46	31.71
2006	30.96	3.91	17.34	18.46	31.71
2007	30.97	3.91	17.35	18.47	31.72

Crude oil, natural gas and liquid prices escalate at 1.5% per year thereafter.

Production

The following table provides a summary of production volumes from our main producing areas.

	Oil and NGL (Bbls/day) 2000	Natural Gas (MCF/day) 2000	Oil and NGL (Bbls/day) 1999	Natural Gas (MCF/day) 1999
Pembina, Alberta	1,025	509	1,062	458
Dodsland, Saskatchewan	406	224	446	306
Pinto, Saskatchewan	79	76	68	57
	1,510	809	1,576	821

Land Holdings

The Company's holdings of petroleum and natural gas leases and rights are as follows:

	2000		1999	
	Gross Acres	Net Acres	Gross Acres	Net Acres
Alberta	36,034	28,080	34,114	26,160
Saskatchewan	29,630	17,768	29,630	17,768
	65,664	45,848	63,744	43,928

Petroleum and Natural Gas Capital Expenditures

The following table summarizes petroleum and natural gas capital expenditures made by the Company on acquisitions, land, seismic, exploration and development drilling and production facilities, net of dispositions for the periods indicated:

Year ended December 31	2000	1999
Acquisitions	$ –	$ –
Exploration and development costs	1,450,237	–
Pipeline projects (battery consolidation)	589,565	122,000
Land costs	399,068	–
Dispositions	–	–
Net petroleum and natural gas capital expenditures	$2,438,870	$ 122,000

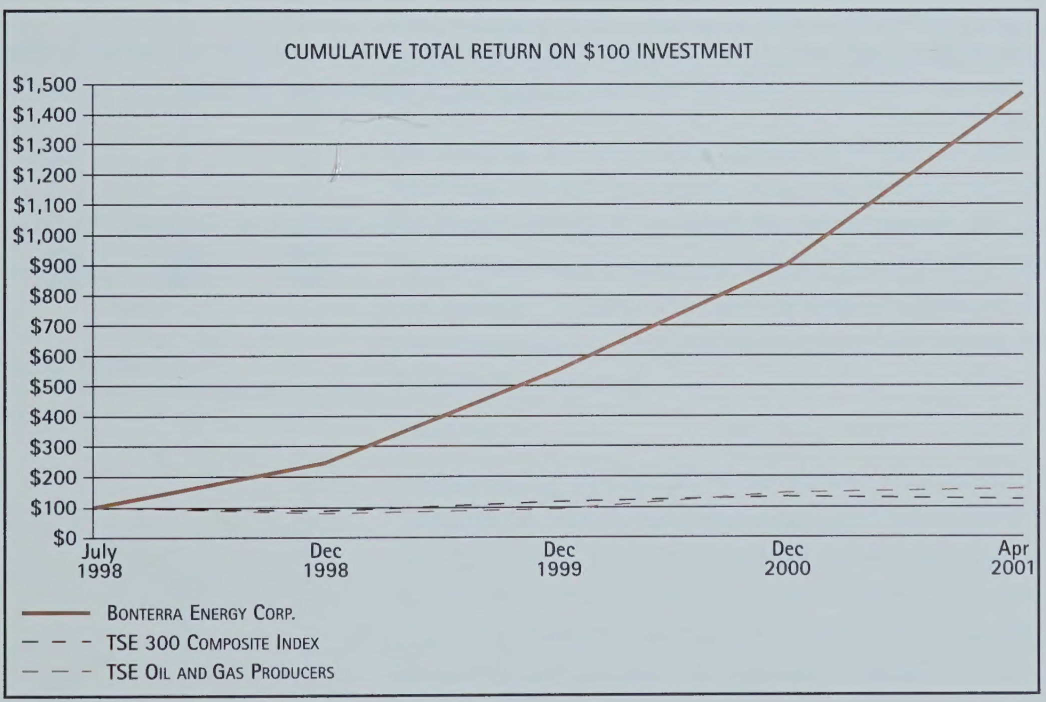
Drilling History

The following table summarizes the Company's gross and net drilling activity and success rates during 2000 and 1999:

	Development Gross	Development Net	Exploratory Gross	Exploratory Net	Total Gross	Total Net
2000						
Crude Oil	1	1	1	.99	2	1.99
Natural Gas	–	–	6	4.65	6	4.65
Dry	–	–	3	2.49	3	2.49
Total	1	1	10	8.13	11	9.13
Success rate	100%	100%	70.0%	69.4%	72.7%	72.7%
1999						
No wells were drilled in 1999.						

Share Performance

The following chart illustrates the returns to shareholders since the Company went public in July, 1998:



Property Discussions

The Company's producing properties are located in the Pembina area of Alberta, the Dodsland area in southwest Saskatchewan, and the Pinto area in southeast Saskatchewan. Bonterra has also acquired exploration property in the Angling and Pembina areas of Alberta.

Pembina Area, Central Alberta

Most of the production from this area is light, sweet gravity crude from the Cardium sandstone formation from a depth of approximately 5,000 feet. This property also has shallow gas potential. Bonterra commenced with a study of the shallow zones and drilled six wells during the latter part of 2000 and Q1, 2001. Results have been favorable and the Company will continue to evaluate undrilled locations on its large land position in this area. The existing infra structure, including pipelines, gas plants and surface leases, has a very positive affect on the economics for this project. Bonterra is also evaluating undrilled oil locations. The property contains approximately 106 gross (88.5 net) operated producing wells with an 84 percent average working interest, and 189 gross (32.1 net) non-operated producing wells with an approximate 17 percent average working interest. Bonterra operates approximately 75 percent of the production from this area.

Dodsland Area, Southwest Saskatchewan

The Dodsland properties produce light sweet gravity oil and solution gas from the Viking sandstone formation at a depth of approximately 2,300 feet. The properties presently contain approximately 360 gross (310 net) operated oil wells with an 88 percent average working interest. Despite the low rates of production on a per well basis (approximately 1.4 barrels per day) the economics for this area is still favorable. Operating costs are approximately $20.00 Cdn. per BOE, but at existing oil prices the field net back per BOE is still about $20.00 Cdn. Under terms of an agreement Bonterra has an option to transfer uneconomic wells to the previous owner of this property. In 2000 Bonterra elected to transfer 43 such wells for abandonment and remediation. Bonterra will be acquiring some additional economic producing wells in this area in 2001.

Pinto Area, Southeast Saskatchewan

The Pinto property produces slightly sour gravity oil and solution gas from the Midale formation. The Company has an average working interest of approximately 95 percent. Bonterra continues to evaluate this area to determine if enhancement programs may succeed in increasing overall production.

General

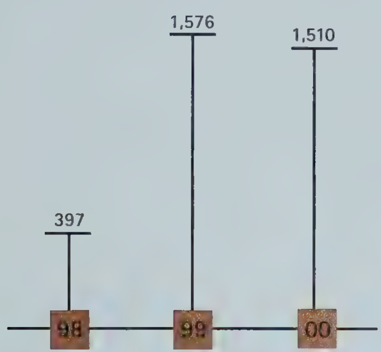
Kindly refer to the "Production" section and "Reserve" section of this report for additional information about these properties. The three properties all have low rates of decline and will all be producing for many years into the future.

Management's Discussion and Analysis

This report is a review of the operations, current financial position and outlook for the Company and should be read in conjunction with the audited financial statements for the fiscal year ended December 31, 2000, together with the notes related thereto.

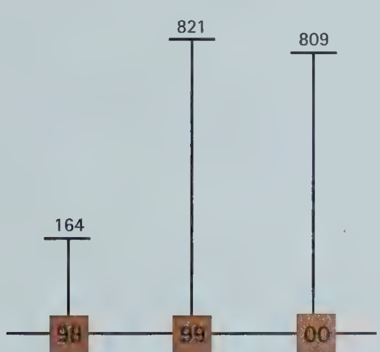
OIL AND NGL PRODUCTION

(BBLS/DAY)



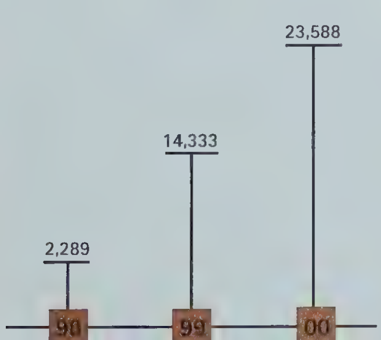
NATURAL GAS PRODUCTION

(MCF/DAY)



GROSS REVENUES

($000)



Production

The Company's average production of oil and natural gas liquids decreased by four percent to 1,510 barrels per day in 2000 from 1,576 barrels per day in 1999. Also the Company's natural gas production decreased by 1.5 percent to 809 MCF per day in 2000 from 821 MCF per day in 1999. The Company drilled two wells (two net) in the third quarter resulting in one natural gas well and one oil well. Production from these wells commenced in late August and early December respectively and are currently producing approximately 60 barrels per day of oil and NGL's and 100 MCF per day of natural gas. In December 2000 the Company tied in approximately 150 MCF per day of natural gas that was previously flared. In December 2000, the Company drilled eight wells in the Pembina area of Alberta. Of these wells, one (.99 net) was an oil well and five (3.65 net) were gas wells. Two (1.99 net) of the wells resulted in dry holes. Four of the gas wells (2.65 net) were on production in late January 2001 and the oil well was placed on production March 4, 2001. Due to pipeline issues the fifth natural gas well is not anticipated to be activated until August. Current net production from these wells is approximately 60 barrels per day oil and NGL's and 600 MCF per day natural gas.

Revenue

Gross revenue from petroleum and natural gas sales for 2000 increased 64.6 percent to $23,588,369 in 2000 compared to $14,332,776 for 1999. In 2000, the average price received for crude oil was $40.42 (1999 - $23.87) per barrel, $5.17 (1999 - $2.80) per MCF of natural gas, and $30.68 (1999 - $14.90) per barrel of NGL's.

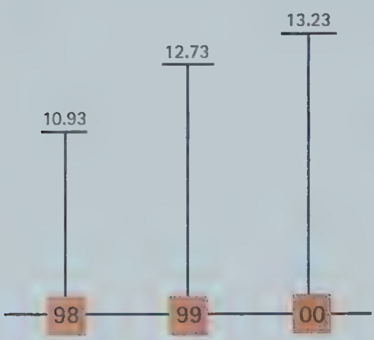
The Company has forward sales agreements in place for 2001 for 475 MCF per day of natural gas at $8.57 Cdn. per MCF (January 1 to March 31, 2001) and for 400 barrels per day of crude oil at a floor price of $44.00 Cdn. and a ceiling price of $47.45 Cdn. (January 1 to June 30, 2001). In addition the Company purchased a $7.35 Cdn. per MCF floor price on 475 MCF per day of natural gas from February 1 to December 31, 2001. The Company frequently reviews its hedging position in conjunction with its cash requirements for capital expenditures and debt payments to determine when or if to enter into forward sales agreements.

Royalties

Royalties paid by the Company consist primarily of Crown royalties paid to the Provinces of Alberta and Saskatchewan. During 2000, the Company paid $1,623,107 (1999 - $950,372) in Crown royalties and $282,923 (1999 - $168,167) in freehold royalties, gross overriding royalties and net carried interests. The majority of the Company's wells are low productivity wells and therefore have low Crown royalty rates. The Company's average Crown royalty rate is approximately 6 percent and approximately 1 percent for other royalties. The Company is eligible for Alberta Crown Royalty rebates on the wells drilled in 2000.

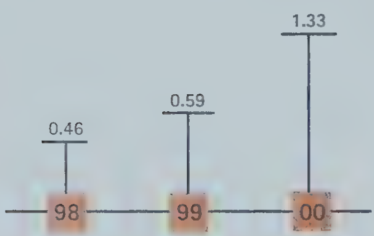
PRODUCTION COSTS

($ PER BOE)



GENERAL AND ADMINISTRATIVE

($ PER BOE)



Production Costs

Production costs decreased marginally to $7,683,670 in 2000 from $7,705,479 in 1999. On a BOE basis operating costs for 2000 were $13.23 compared to $12.73 for 1999. Due to low production from each well, BOE costs in the Dodsland area of southwest Saskatchewan averaged $20.31 (1999 - $21.21). In May 2000, the Company returned 43 uneconomic wells to the operator of the property in accordance with its operating agreement. This resulted in a reduction of approximately $350,000 per year of operating costs and 25 barrels per day of production.

Production costs on the Company's operated Pembina and Pinto properties averaged $10.78 per BOE in 2000 compared to $9.44 per BOE in 1999. The increase was due to several workovers on existing producing wells to enhance production rates. As a result of these workovers, the Company was able to maintain a less than three percent decline rate on its existing production.

General and Administrative Expense

General and administrative expenses increased to $769,795 in 2000 from $356,123 in 1999. On a BOE basis, general and administrative expenses increased to $1.33 in 2000 from $0.59 in 1999. The increase was due primarily to an increase of $499,500 in the Company's management fee. The management fee charged by Comstate Resources Ltd. (Comstate) (see below) is calculated based on 5 percent of before tax net income plus a monthly fee of $10,000 (1999 - $5,000). Costs associated with corporate services and production accounting declined approximately $32,000 or 14.7 percent. In addition, the Company capitalized approximately $43,000 in general and administrative costs

The Company has entered into a management agreement with Comstate to provide field operations, management and general office services. Fees charged for field operations are charged on a per well basis. Fees associated with well operations are charged to production costs as incurred.

Interest Expense

Interest expense for 2000 declined 37 percent to $719,967 compared to $1,144,121 in 1999. The decline is attributable to repayment of approximately $11,120,000 of outstanding debt during the year. At December 31, 2000, the Company had outstanding loans to its principal banker of $3,928,365 (December 31, 1999 - $8,548,436) and to Comstate of Nil (December 31, 1999 - $6,500,000). Interest rate charges during 2000 on the outstanding debt to Comstate were Canadian chartered bank prime plus one half percent and to its principal banker, Canadian chartered bank prime plus one quarter of one percent. The Company has the ability to use Bankers Acceptances (BA's) as part of its loan facility. Interest charges on BA's are generally one half percent lower than that charged on the general loan account.

Depletion, Depreciation, Future Site Restoration and Dry Hole Costs

The Company depletes its oil and natural gas intangible assets using the unit-of-production basis by field. For tangible assets such as well equipment, a life span of ten years is estimated and the related tangible costs are depreciated at one-tenth of original cost per year. Provisions are made for future site restoration based on management's estimation of abandonment requirements using current costs and amortized on a unit-of-production basis by field.

For the fiscal year ending December 31, 2000, the Company expensed $2,414,298 for the above-described items. This compares to $2,614,005 expensed in 1999.

The Company follows the successful efforts method of accounting for petroleum and natural gas exploration and development costs. Under this method, the costs associated with dry holes are charged to operations. During 2000, the Company's drilling program resulted in three (2.49 net) dry holes for net costs of $449,013 . The Company did not participate in drilling any wells in 1999.

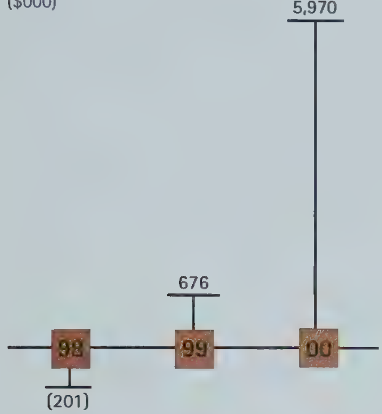
Income Taxes

Current taxes of $3,254,103 (1999 - $213,820) consist of federal and provincial income taxes of $2,946,334 (1999 – Nil) and $307,769 (1999 - $213,820) related to federal large corporation tax and the Saskatchewan resource surcharge. The Company's primary tax pools are Canadian

oil and gas property expense ($12,456,454) and well equipment costs ($2,139,813) that can be written off at an annual rate of 10 and 25 percent respectively on a declining balance basis. Due to high net income and the low acquisition cost for its properties that results in low tax pool amounts, Bonterra is unable to completely shelter its income from federal and provincial income taxes.

NET EARNINGS (LOSS)

($000)



Net Earnings

The Company is extremely pleased to report net earnings of $5,970,124 (1999 - $675,601). This represents a return of capital employed of 192.6 percent. As a result of our aggressive acquisition strategy in 1998, the Company obtained its primary assets at an average cost of $2.60 per BOE of proven reserves. At December 31, 2000 the Company's current average capital cost is $2.43 per BOE of proven reserves. This combined with an average production decline of less than three percent and numerous new zone exploration and development opportunities on our existing producing properties as well as newly acquired properties should enable Bonterra to continue to generate substantial net earnings in 2001.

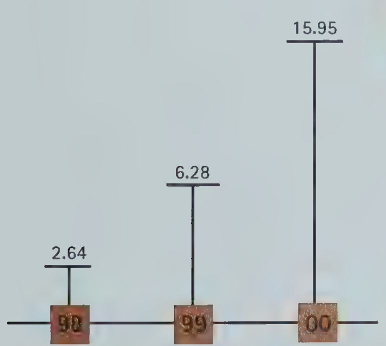
Cash Flow From Operations

Cash flow from operations for the fiscal year ending December 31, 2000, increased 145 percent to $9,385,724 ($0.27 per fully diluted average outstanding share) compared to $3,829,103 ($0.11 per fully diluted average outstanding share) in 1999. Anticipated operating cost reductions per BOE, projected continued high oil and natural gas prices, and increased production should substantially increase the Company's 2001 cash flow.

Cash Netback

CASH NETBACKS

($ Per BOE)



The following table illustrates the Company's cash netback:

$ Per BOE	2000	1999
Production volumes (BOE)	580,572	605,084
Gross production revenue	$ 40.63	$ 23.69
Royalties	(3.28)	(1.85)
Field operating	(13.23)	(12.73)
Field netback	24.12	9.11
General and administrative	(1.33)	(0.59)
Interest	(1.24)	(1.89)
Taxes	(5.60)	(0.35)
Cash netback	$ 15.95	$ 6.28

Liquidity and Capital Resources

During 2000, the Company participated in drilling 11 gross (9.13 net) wells at a total cost of $1,450,237. Of these wells, two (two net), one gas and one oil well, were completed and on production by December 31, 2000. Subsequent to year end a second (.99 net) oil well and four (2.65 net) gas wells were tied in prior to printing of this report. The 2000 drilling program also resulted in three (2.49 net) dry holes.

The Company also acquired three sections of undrilled land during the year. Drilling on these lands is scheduled for late spring or summer of 2001.

To assist in reducing operating costs and to gather previously flared natural gas production, the Company consolidated several battery locations in its Pembina area of Alberta at a total cost of $589,565. This will provide additional natural gas revenue and reduced operating costs in future years.

At December 31, 2000, the Company had bank debt of $3,928,365. Bonterra's credit facility at year-end consisted of a revolving line of credit

of $10,000,000 and carried an interest rate of one quarter percent above Canadian chartered bank prime. Bonterra has issued letters of credit in the amount of $1,419,714 to the Province of Alberta for future abandonment costs. Net of the letters of credit, the Company's available line of credit under the above mentioned facility is $8,580,286. The letters of credit are reduced on a per well basis upon notification of abandonment or reactivation of specified wells.

The credit facility allows for borrowings by means of Bankers Acceptances (BA's). The effective interest rates of BA's are generally half a percentage point lower than that otherwise available under the credit facility. The Company makes maximum use of BA's to reduce overall interest costs. Collateral for the loan consists of a demand debenture providing a first floating charge over all of the Company's assets and a general security agreement.

The Company has repaid its outstanding loan to Comstate Resources Ltd. in 2000 (1999 - $6,500,000). The loan was acquired to assist in financing the Company's November 1, 1998 major oil and gas acquisition. Repayments of the loan as well as interest payments thereon were limited to Company cash flow as determined by accounting principles generally accepted in Canada. Due to the secondary nature of the loan, the interest rate charged by Comstate was Canadian chartered bank prime plus one half percent compounded quarterly.

At December 31, 2000, the Company has 2,909,000 stock options issued under its Stock Option Plan. The options vest over a three year period and must be exercised on or before May 1, 2003. The stock options range in price from $0.10 to $0.55 (the trading price on the day the options were issued) with an average exercise price of $0.13 per share.

Business Prospects, Risks, and Outlooks

The resource industry operates with a great deal of risk. The most significant risks may come from oil and natural gas price swings, the uncertainty of finding new reserves from drilling programs or acquisitions, competition within the industry, and increasing environmental controls and regulations.

The prices received for crude oil are established by world market forces and for natural gas by forces within North America. Fluctuations in pricing can have extremely positive or negative effects on the Company's cash flow or in the value of its producing and non-producing oil and natural gas properties.

Bonterra presently attempts to minimize these risks by pursuing both oil and natural gas activities. The Company may sometimes elect to protect against price fluctuation by using commodity hedging. The Company operates its oil and natural gas interests in areas which have long life reserves; where it has the technical expertise to enhance production, control operating costs and to increase margins of profit.

As outlined in the Report to Shareholders section of this report the Company will be asking shareholders to vote on a major corporate restructure program at the annual and special meeting in June, 2001. Kindly refer to this section for details about the restructuring.

Sensitivity Analysis

Sensitivity analysis as estimated for 2000 follow:

	Cash Flow	Cash Flow Per Share
U.S. $1.00 per barrel	$543,000	$0.017
Canadian $0.10 per MCF	$ 61,000	$0.002
Change of Canadian $0.01/U.S. $ exchange rate	$228,000	$0.007

Management's Responsibility for Financial Statements

The information provided in this report, including the financial statements, is the responsibility of management. In the preparation of the statements, estimates are sometimes necessary to make a determination of future values for certain assets or liabilities. Management believes such estimates have been based on careful judgements and have been properly reflected in the accompanying financial statements.

Management maintains a system of internal controls to provide reasonable assurance that the Company's assets are safeguarded and to facilitate the preparation of relevant and timely information.

Deloitte & Touche LLP has been appointed by the shareholders to serve as the Company's external auditors. They have examined the financial statements and provided their auditors' report. The audit committee has reviewed these financial statements with management and the auditors, and has reported to the Board of Directors. The Board of Directors has approved the financial statements as presented in this annual report.

George F. Fink
President

Garth E. Schultz
Vice President, Finance

Auditors' Report

To the Shareholders of Bonterra Energy Corp.:

We have audited the balance sheets of **Bonterra Energy Corp.** as at December 31, 2000 and 1999 and the statements of earnings and retained earnings and cash flow for the years then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as, evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2000 and 1999, and the results of its operations and its cash flow for the years then ended in accordance with Canadian generally accepted accounting principles.

Deloitte & Touche LLP

Chartered Accountants

Calgary, Alberta
March 23, 2001

Balance Sheets

As at December 31	2000	1999
Assets		
Current		
Accounts receivable	$ 3,003,717	$ 2,539,000
Inventories	104,022	73,637
Prepaid expenses	231,591	158,087
	3,339,330	2,770,724
Abandonment deposit (Note 2)	–	1,213,378
Property and Equipment (Note 3)		
Property and equipment	22,114,586	20,124,728
Accumulated depletion and depreciation	(3,484,082)	(1,878,928)
Net property and equipment	18,630,504	18,245,800
	$21,969,834	$22,229,902
Liabilities		
Current		
Bank indebtedness	$ 98,151	$ 589,013
Accounts payable and accrued liabilities	3,153,852	1,969,406
Income taxes payable	3,030,000	172,292
Current portion of long-term debt (Note 4)	–	6,500,000
	6,282,003	9,230,711
Long-term debt (Note 4)	3,928,365	8,548,436
Future income tax liability (Note 6)	719,952	167,663
Future site restoration	1,769,379	997,281
	12,699,699	18,944,091
Shareholders' Equity		
Share capital (Note 5)	3,099,629	3,085,429
Retained earnings	6,170,506	200,382
	9,270,135	3,285,811
	$21,969,834	$22,229,902

On Behalf of the Board:

George F. Fink
Director

F. William Woodward
Director

Statements of Earnings and Retained Earnings

Years ended December 31	2000	1999
Revenue		
Oil and gas sales, net of royalties of $1,906,030 (1999-$1,118,539)	$21,682,339	$13,214,237
Production costs	(7,683,670)	(7,705,479)
Interest and other	130,920	34,409
	14,129,589	5,543,167
Expenses		
General and administrative	769,795	356,123
Interest on long-term debt	719,967	1,144,121
	1,489,762	1,500,244
Cash Flow From Operations Before Current Income Taxes	12,639,827	4,042,923
Depletion, depreciation and future site restoration	2,414,298	2,614,005
Dry holes	449,013	–
	2,863,311	2,614,005
Earnings Before Income Taxes	9,776,516	1,428,918
Income Taxes (Note 6)		
Current	3,254,103	213,820
Future	552,289	539,497
	3,806,392	753,317
Net Earnings For The Year	$ 5,970,124	$ 675,601
Retained earnings (deficit), beginning of year	200,382	(475,219)
Retained Earnings, End of Year	$ 6,170,506	$ 200,382
Net Earnings Per Share (Basic)	$ 0.19	$ 0.02
Net Earnings Per Share (Fully Diluted)	$ 0.17	$ 0.02

Statements of Cash Flow

Years ended December 31	2000	1999
Operating Activities		
Net earnings for the year	$ 5,970,124	$ 675,601
Items not affecting cash		
Depletion, depreciation and future site restoration	2,414,298	2,614,005
Dry holes	449,013	–
Future income taxes	552,289	539,497
Cash flow from operations	9,385,724	3,829,103
Change in non-cash operating working capital items	2,152,793	(120,980)
	11,538,517	3,708,123
Financing Activities		
Repayment of long-term debt	(11,120,071)	(2,835,322)
Issuance of common shares	14,200	7,700
	(11,105,871)	(2,827,622)
Investing Activities		
Property and equipment expenditures	(1,155,162)	(253,911)
Abandonment deposit (Note 2)	1,213,378	(1,213,378)
	58,216	(1,467,289)
Net cash inflow (outflow)	490,862	(586,788)
Bank indebtedness, beginning of year	(589,013)	(2,225)
Bank Indebtedness, end of year	$ (98,151)	$ (589,013)

1. SIGNIFICANT ACCOUNTING POLICIES

Property and Equipment

Petroleum and Natural Gas Properties and Related Equipment

The Company follows the successful efforts method of accounting for petroleum and natural gas properties and related equipment. Costs of acquiring unproved properties are capitalized and amortized on a straight-line basis over the lives of the related leases. When property is found to contain proved reserves as determined by Company engineers, the related net book value is depleted on the unit-of-production basis, calculated by field. The costs of dry holes and abandoned properties are charged to operations. Geological costs, lease rentals and carrying costs are charged to income as incurred. Costs of drilling exploratory and development wells that result in additions to proven reserves are capitalized and depleted on the unit-of-production basis. Tangible equipment is depreciated on a straight-line basis over ten years.

Furniture, Fixtures and Office Equipment

Other assets are recorded at cost and depreciated over a three to ten year period representing their estimated useful lives.

Income Taxes

The Company follows the liability method of accounting for income taxes under which the income tax provision is based on the temporary differences in the accounts calculated using income tax rates expected to apply in the year in which the temporary differences will reverse.

Future Site Restoration

The Company provides for future site restoration and abandonment costs over the estimated production life of its property and equipment. Estimates of these amounts are based on the anticipated method and extent of site restoration using current costs and in accordance with existing legislation and industry practice. The annual charge is included with depletion, depreciation and future site restoration.

Stock-based Compensation Plan

The Company has a stock-based compensation plan as described in Note 5. No compensation expense is recognized for the plan when stock or stock options are issued. Consideration paid on exercise of stock options is credited to share capital.

Joint Interest Operations

Significant portions of the Company's oil and gas operations are conducted with other parties and accordingly the financial statements reflect only the Company's proportionate interest in such activities.

Inventories

Inventories consist of materials and supplies that are valued at the lower of cost or net realizable value.

Net Earnings Per Common Share

Net earnings per common share is calculated using the weighted average number of common shares outstanding during the period, which was 31,678,406 (1999 - 31,542,239). The exercise of outstanding stock options would have a dilutive effect on net earnings of $0.02 (1999 - $0.00) per common share.

2. ABANDONMENT DEPOSIT

In 1999, the Company was required under Province of Alberta Regulations to provide a cash deposit with the Alberta Energy and Utilities Board for the future abandonment of specified inactive wells. The Province of Alberta amended the abandonment deposit rules in 2000 to allow for the provision of letters of credit to replace cash deposits. The Company has issued letters of credit of $1,419,714 and has recovered its cash deposits. The letters of credit are reduced on a per well basis if a well is reactivated or abandoned and the surface reclaimed.

3. PROPERTY AND EQUIPMENT

	2000 Cost	2000 Accumulated Depletion and Depreciation	1999 Cost	1999 Accumulated Depletion and Depreciation
Undeveloped Land	$ 399,068	$ –	$ –	$ –
Petroleum and natural gas properties and related equipment	21,689,951	3,476,841	20,099,161	1,875,307
Furniture, equipment and other	25,567	7,241	25,567	3,621
	$ 22,114,586	$ 3,484,082	$20,124,728	$ 1,878,928

During the year, $42,796 (1999 - $0) of general and administrative expenses were capitalized.

4. LONG-TERM DEBT

The Company has a long-term bank revolving credit facility of $10,000,000 at December 31, 2000. The terms of the credit facility provide that the loan is due on demand and is subject to annual review. The credit facility has no fixed payment requirements. The amount available for borrowing under the credit facility is reduced by the amount of outstanding letters of credit (see note 2). Collateral for the loan consists of a demand debenture providing a first floating charge over all of the Company's assets, and a general security agreement. The credit facility carries an interest rate of one quarter percent above Canadian chartered bank prime.

At December 31, 2000, the Company had fully repaid its outstanding loan with a related non-banking public company (1999 - $6,500,000). The loan was repayable upon demand but was subject to the current loan agreement with the Company's banker, which provided that the loan could only be repaid if the Company maintained a combination of working capital and unutilized balance in its bank credit facility of $1,000,000. The loan was unsecured, and carried interest at one half percent above Canadian chartered bank prime. During the year the Company incurred interest of $272,378 on this loan from the related party.

The Company has engaged the services of the related party to provide management and operational services on a fee basis for operating the Company's petroleum and natural gas properties.

Cash interest paid during 2000 for both of the above described loans was $719,967 (1999 - $1,168,495).

SHARE CAPITAL

Authorized

The Company is authorized to issue an unlimited number of common shares without nominal or par value

Issued	2000 Number	2000 Amount	1999 Number	1999 Amount
Common Shares				
Balance, beginning of period	31,588,906	$ 3,085,429	15,755,953	$ 3,077,729
Exercise of stock options prior to stock split	–	–	18,000	3,600
Stock split	–	–	15,773,953	–
Exercise of stock options after stock split	106,000	14,200	41,000	4,100
Balance, end of year	31,694,906	$ 3,099,629	31,588,906	$ 3,085,429

On July 26, 1999, the Company split its common shares by issuing an additional share for every outstanding share.

The Company provides a stock option plan for its directors, officers, employees and consultants. Under the plan, the Company may grant options for up to 4,317,000 shares of common stock. The exercise price of each option granted equals the market price of the Company's stock on the date of grant and the option's maximum term is five years. Options vest one-third each year for the first three years of the option term.

A summary of the status of the Company's stock option plan as of December 31, 2000 and 1999, and changes during the years ending on those dates is presented below:

Fixed Options	2000 Shares	2000 Weighted-Average Exercise Price	1999 Shares	1999 Weighted-Average Exercise Price
Outstanding at beginning of year	3,091,000	$ 0.13	1,434,000	$ 0.20
Granted prior to stock split	–	–	66,000	0.47
Options exercised prior to stock split	–	–	(18,000)	0.20
Stock split	–	–	1,482,000	–
Granted after stock split	36,000	0.55	168,000	0.50
Options cancelled	(112,000)	0.10	–	–
Options exercised after stock split	(106,000)	0.10	(41,000)	0.10
Outstanding at end of year	2,909,000	$ 0.13	3,091,000	$ 0.13
Options exercisable at end of year	1,885,000		1,003,000	

The following table summarizes information about fixed stock options outstanding at December 31, 2000:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding At 12/31/00	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number Exercisable At 12/31/00	Weighted-Average Exercise Price
$0.10	2,581,000	2.3 years	$0.10	1,681,000	$0.10
0.225 to 0.55	328,000	2.4	0.40	204,000	0.39
$0.10 to 0.55	2,909,000	2.3 years	$0.13	1,885,000	$0.13

6. INCOME TAXES

The Company has recorded a future income tax liability. The liability relates to the following temporary differences:

	2000 Amount	1999 Amount
Temporary differences related to assets and liabilities	$ 756,158	$ 356,721
Finance expense charged to shareholders' equity	(36,206)	(53,691)
Tax loss carry forward	–	(135,367)
	$ 719,952	$ 167,663

Income tax expense varies from the amounts that would be computed by applying Canadian federal and provincial income tax rates as follows:

	2000	1999
Earnings before income taxes	$ 9,776,516	$1,428,918
Combined federal and provincial income tax rates	44.60%	44.30%
Income tax provision calculated using statutory tax rates	4,360,326	633,011
Increase(decrease) in income taxes resulting from:		
Non-deductible crown royalties	746,280	478,499
Resource allowance	(1,600,826)	(592,643)
Other	(7,157)	20,950
Capital taxes	307,769	213,500
	$ 3,806,392	$ 753,317

The Company paid $396,395 of its tax liability in 2000 (1999 - $79,847). The balance of the Company's current income taxes payable as disclosed in the balance sheet has been paid in 2001.

The Company has the following tax pools, which may be used to reduce taxable income in future years, limited to the applicable rates of utilization:

	Rate of Draw Down %	Amount
Undepreciated capital costs	20-100	$ 2,663,663
Canadian oil and gas property expenses	10	12,456,454
Canadian development expenses	30	184,932
Finance expenses	20	81,179
		$15,386,228

7. FINANCIAL INSTRUMENTS

The carrying value of the financial instruments of the Company approximates their estimated fair values. Financial instruments include accounts receivable, accounts payable and accrued liabilities, income taxes payable and current and long-term debt.

8. COMMITMENTS

The Company entered into the following commodity hedging transactions in 2000 for a portion of its 2001 production:

Period of Agreement	Commodity	Volume per day	Index	Price (Cdn.)
January 1, to June 30, 2001	Crude Oil	400 barrels	WTI	$44 floor to $47.45 ceiling
January 1, to March 31, 2001	Natural Gas	500 GJ's	AECO	$8.14 per GJ

9. COMPARATIVE FIGURES

Certain prior year's amounts in the financial statements have been reclassified to conform to the presentation adopted in 2000.

10. SUBSEQUENT EVENT

On March 15, 2001 the Company announced that it will proceed with a corporate reorganization that will result in the Company becoming a Royalty Income Trust (Income Trust). The transaction will be completed by way of a Plan of Arrangement (the "Arrangement"). The Arrangement will result in the shareholders of the Company receiving one trust unit in the Income Trust in exchange for each four common shares in the Company.

The completion of the reorganization into an Income Trust is subject to receiving approvals from the Company's shareholders, the court and regulatory approvals. The transaction is anticipated to be effective July 1, 2001.

Corporate Information

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T2P 3Y7

Board of Directors

G. J. Drummond
Calgary, Alberta
G. F. Fink
Calgary, Alberta
C. R. Jonsson
Vancouver, British Columbia
F. W. Woodward
Calgary, Alberta

Officers

G. F. Fink - President
R. M. Jarock - Operations Manager and
Vice President, Acquisitions
S. L. Safronovich - Vice President, Operations
G. E. Schultz - Vice President,
Finance, and Secretary

Registrar and Transfer Agent

Olympia Trust Company
Calgary, Alberta

Auditors

Deloitte & Touche LLP
Calgary, Alberta

Solicitors

Parlee McLaws
Calgary, Alberta
Tupper, Jonsson & Yeadon
Vancouver, British Columbia

Bankers

The Royal Bank of Canada
Calgary, Alberta

Stock Listing

The Canadian Venture Exchange
Vancouver, British Columbia
Trading Symbol: BON

Web Site

www.bonterraenergy.com

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